

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 98-496

October 13, 1998

PUBLIC UTILITIES COMMISSION
Load Obligation and Settlement
Calculations for Competitive Providers
of Electricity (Chapter 321)

ORDER ADOPTING RULE
AND STATEMENT OF
POLICY BASIS

WELCH, Chairman; NUGENT and DIAMOND, Commissioners

I. INTRODUCTION

In this Order, we adopt rules governing the process, methods and terms by which transmission and distribution utilities will develop the hourly load estimates and monthly energy reconciliations of competitive electricity providers' load obligations. The rule includes load profiling and individual customer metering requirements.

Transmission and distribution utilities will provide the estimates to the bulk power system administrators operating in Maine. The administrators will balance each competitive electricity provider's hourly load obligations with the provider's delivered generation to determine the appropriate financial settlement between the bulk power system administrators and the competitive electricity provider.

II. BACKGROUND

During its 1997 session, the Legislature fundamentally altered the electric utility industry in Maine by deregulating electric generation services and allowing for retail competition beginning on March 1, 2000.¹ At that time, Maine's electricity consumers will be able to choose a generation provider from a competitive market. As part of the restructuring process, the Act requires utilities to divest their generation assets and prohibits their participation in the generation services market.

Concurrently, NEPOOL and the recently created ISO-NE are revising existing structures and procedures to accommodate wholesale and retail deregulation. ISO-NE will schedule regional generation dispatch and administer a regional bidding pool for energy and other energy-related products.

¹ An Act to Restructure the State's Electric Industry (the Act), P.L. 1997, ch. 316, codified as 35-A M.R.S.A. §§ 3201-3217.

Northern portions of Maine operate in the Maritimes control area. Processes for implementing retail access for customers in the Maritimes control area are under review by the Commission at this time.

While ISO-NE and Northern Maine procedures are not yet fully developed, it is clear that effective operation of retail access will require bulk power system administrators to balance the retail load obligations of each competitive electricity provider with the generation delivered by the provider. To accomplish this balancing, ISO-NE² will be informed daily of each competitive electricity provider's expected load obligation for the following day to allow adequate regional generation dispatch. In addition, at the end of each day, the loads recently served by each competitive electricity provider must be estimated to allow ISO-NE to track system reliability and to allow providers to predict their obligation in future days. Finally, at the end of each month, ISO-NE is expected to balance each competitive electricity provider's load obligations and generation delivery for the purpose of financial settlement among competitive electricity providers.

The purpose of this rule is to implement a mechanism within Maine to provide the necessary data to ISO-NE in a manner that ensures timeliness, accuracy, and equity among all competitive electricity providers selling retail electricity in Maine. The mechanism must also conform with the procedures used throughout ISO-NE's region in order for ISO-NE to manage the region comprehensively. As with all rules we are implementing to accomplish retail competition on March 1, 2000, we have attempted to adopt a rule that is consistent with regional operations, that can be implemented successfully before March 1, 2000, that does not cause unnecessary costs, and that creates a market that facilitates the participation of sellers of retail electricity.

This rule addresses the mechanisms that transmission and distribution utilities will use to report day-after and month-end loads to ISO-NE. Transmission and distribution utilities will not take part in day-ahead projections of competitive electricity providers' load obligations.

III. GENERAL CONSIDERATIONS

Various conditions currently exist in the region that may change quickly over time and that influence the provisions of this rule. First, the rule puts in place operations that satisfy what we anticipate the requirements of bulk power system administrators will be, at a time when those requirements have

²We will refer to ISO-NE operations with the understanding that the comments also refer to processes yet to be developed in Northern Maine.

not been fully developed. ISO-NE and NEPOOL are in the early stages of revising their settlement processes to accommodate retail competition.

At this time, we can envision the likely outcome of their revisions based on current NEPOOL operations, the needs of the process, and solutions developed elsewhere in the region, but we cannot know with certainty what will be required of Maine's transmission and distribution utilities or competitive electricity providers. In addition, requirements will evolve in response to regional needs. Northern Maine's settlement requirements are even more uncertain. Therefore, to the greatest extent possible the rule includes the flexibility to revise processes as ISO-NE and the corresponding Northern Maine administrator's requirements emerge.

Second, current metering and communication technology cannot cost-effectively measure hourly loads of each customer of each competitive electricity provider. Over time, falling meter prices may allow more comprehensive hourly load measurement. However, the rule at this time must create processes to estimate loads in circumstances when they are not available.

Related to this issue, metered customer loads will not, in aggregate, equal the total metered load obligation that must be provided to ISO-NE. This is true because of line losses and because of the necessity to estimate rather than meter much of the region's load. ISO-NE will require that day-after and month-end data reported to it precisely equal the hourly loads measured at bulk system meters of the transmission and distribution utilities in Maine. Therefore, the rule must include techniques to adjust estimated loads daily to equal total bulk metered loads.

Third, the rule encompasses complex statistical and data processing procedures that are maturing in response to regional needs. Therefore, the rule provides enough flexibility to allow transmission and distribution utilities to incorporate improving methods over time.

Finally, Maine has both investor-owned utilities (IOUs) that serve the majority of the State's load, and consumer-owned utilities (COUs) with far smaller loads, often no transmission plant, and few employees. These differences have led us to include practical options for the COUs that will allow us to accomplish the goals of the rule without creating a disproportionate cost burden on small utilities' customers.

For example, in its comments Dirigo³ stated that its members are generally not members of NEPOOL because they own no

³Dirigo Electric Cooperative is a cooperative of

transmission facilities, and therefore are not required to report data to ISO-NE. We agree with Dirigo's assessment that COUs would be required to join NEPOOL in order to report load data. Membership would undoubtedly impose costs on small utilities who may receive relatively fewer benefits through membership. Therefore, we have developed options for the smaller utilities that will allow COUs to avoid unnecessary costs through such approaches as allowing neighboring IOUs, who are NEPOOL members, to develop and report COUs' load data.

Similarly, we understand that the smallest utilities would find the data processing required for sampling and for settlement to be relatively more costly than would larger entities. We suspect that, while complex procedures are necessary to accommodate large groups of customers, similar procedures are overly sophisticated in smaller environments. For example, the load profile of a customer within a small COU and the profile of a customer within the neighboring IOU may be more similar than the profiles of diverse customers within the IOU, in which case separate sampling would be an unnecessary use of rate payer money. We made this concern clear in our NOI and in the proposed rule, and asked for comments on ways for COUs to accomplish settlement. As a result, the rule contains options for compliance by COUs that avoid incurring disproportionate costs. For example, the rule allows COUs to combine with neighboring IOUs to perform their profiling and/or their settlement functions. Additionally, the rule allows COUs to create a load profile describing as a single class the usage of all customers of the COU.

Finally, the rule allows COUs to petition the Commission with additional suggestions for cost-effective settlement.

IV. RULEMAKING PROCESS

On July 24, 1998, we issued a Notice of Rulemaking and a proposed rule on load obligation and settlement calculations. Prior to initiating the formal rulemaking process, we conducted an Inquiry in Docket No. 97-861. We solicited written comments by issuing Notices of Inquiry on December 2, 1997 and on March 3, 1998. Two technical conferences were held, on February 11, 1998 and June 16, 1998. To solicit complete information on the issues, we invited comment from parties who have expressed interest in restructuring in Maine, from competitive electricity providers operating in the region, and from ISO-NE. Consistent

consumer-owned utilities whose members are: Eastern Maine Electric Cooperative, Fox Island Electric Cooperative, Houlton Water Company, Kennebunk Light and Power District, Madison Electric Works, and Van Buren Light and Power District.

with rulemaking procedures, interested persons were provided an opportunity to file written comments on the proposed rule.

During the inquiry stage, we received written comments from Bangor Hydro-Electric Company, Central Maine Power Company, Dirigo Electric Cooperative, Eastern Maine Electric Cooperative, ENRON, MainePower, Maine Public Service Company and the State Planning Office. In response to the Notice of Rulemaking, we received comments from Bangor Hydro-Electric Company, Central Maine Power Company, Dirigo Electric Cooperative, Logica Incorporated, MainePower, and Maine Public Service Company. Finally, we considered the processes implemented in other New England states.

V. DISCUSSION OF RULE AND COMMENTS

In the following sections, we discuss the provisions of the rule, positions of commenters, and our rationale for either maintaining or modifying the provisions of the proposed rule.

A. General Principles

When we developed the proposed rule, we considered three overarching principles: consistency in methods throughout the State, cost minimization, and specificity of profiling and settlement-estimation methods. The final rule continues to embody these three principles. However, in response to comments, the final rule more heavily emphasizes flexibility in methods in order to avoid unnecessary costs.

Commenters during the Inquiry stage stated strongly that consistent methods would lower barriers to market entry by minimizing complexity and confusion. A limited number of well-understood methods for estimating loads would increase predictability, affording greater financial stability. As Logica and BHE commented, cost savings would result from coordinating methods and choosing a common vendor or developing joint software. Consistency would minimize complaints by competitive electricity providers that believe they have been disadvantaged by a settlement calculation.

On the other hand, many transmission and distribution utilities in Maine currently perform load research that produces data similar in content to that required for the daily ISO-NE reporting addressed by this rule. This research is complex and costly. A variety of methods are accepted by the industry for costing and ratemaking purposes. As commenters suggested in all phases of the rulemaking process, allowing transmission and distribution utilities to continue existing methods will minimize costly software redevelopment or resampling.

The final rule strikes the balance between consistency and flexibility that we find to be appropriate for the early years of retail access.

B. Section 1: Definitions

Section 1 defines terms used in this rule.

C. Section 2: Transmission and Distribution Utility Obligation

Section 2.A states that each transmission and distribution utility is responsible for carrying out the rule within its territory.

Dirigo stated that transmission and distribution utilities are not the appropriate entities to provide load data to ISO-NE. Dirigo stated that each competitive electricity provider should estimate and submit its own region-wide load data and should submit those data to each transmission and distribution utility to monitor; if the transmission and distribution utility discovers that load estimates from the providers in its territory disagree with bulk meter readings, the utility would notify ISO-NE of the discrepancy and provide an adjustment.

We have not adopted Dirigo's recommended approach for all utilities because it is not currently workable. As discussed above, each hour's load estimates must agree with bulk power meter readings in the region in order for regional loads to be adequately managed. As long as it is necessary to use load profiles to estimate hourly provider loads, the sum of those estimates (even after adjustment for line losses) is unlikely to equal the bulk power meter readings because of sampling inaccuracies. Further, the discrepancy will occur in every hour of every day. The method developed in this rule eliminates these discrepancies in order to provide ISO-NE with the data it requires. No one provider is capable of knowing the hourly discrepancies. Only an entity that assesses the bulk power meter readings and that knows every competitive electricity provider's estimated load in each hour can determine the hourly discrepancies. Furthermore, no one provider knows what portion of the discrepancies it should allocate to its own loads. Only an entity that possesses all competitive electricity providers' estimated loads can allocate the discrepancies equitably, reliably, and consistently to all providers. Clearly, that one entity is the transmission and distribution utility. Therefore, only the transmission and distribution utility can effectively calculate hourly load estimates that are accurate and equitable.

Taking these facts into consideration, it appears likely that Dirigo's recommended approach would require daily adjustments to providers' hourly load estimates by the transmission and distribution utilities that are monitoring those calculations, which is essentially the process required by the rule.

In Sections 2.B and 2.C, we added language to exclude aggregators and brokers from the rule and to clarify that the rule's provisions apply to each standard offer provider. Aggregators and brokers do not take title to electricity and are thus not responsible for settlement with ISO-NE. Therefore, transmission and distribution utilities should not estimate loads for aggregators and brokers.

Section 2.D expands the proposed rule to include a variety of options that would allow COUs to comply with the goals of the rule without incurring disproportionate costs. The final rule contains three options, and in addition allows a COU to petition the Commission to adopt any other reasonable option. The first option allows a COU to effectively become part of its surrounding IOU for the purposes of allowing the IOU to report the load obligations within the COU as if those obligations occurred within the IOU's own territory. This option would eliminate the need for the COU to join NEPOOL, allow the calculations to be carried out by an entity that already possesses the software and expertise to do it, and increases statewide consistency. The second option allows a COU to adopt the load profiles of profile groups in its neighboring IOU. This option would eliminate the sampling step, but would not eliminate the need for COUs to report hourly loads to ISO-NE. The third option allows a COU to eliminate before-the-fact profile calculation by calculating a simplified, system-wide profile each day based on bulk meter and telemetered data. This option also does not eliminate the need for the COU to report hourly loads to ISO-NE.

When these options are exercised or when other reasonable methods exist for combining COU and IOU operations, we direct IOUs to accommodate them. CMP and BHE commented that there are costs associated with providing data or calculations for COUs, and we have added language to allow IOUs to recover from COUs the reasonable costs of providing any function specified in this rule. The rule specifies "reasonable," not "incremental" cost, meaning that IOUs may charge a portion of their overall average costs to accommodate COU operations.

In its comments, MainePower and Logica disagreed with the proposed rule's provision to allow COUs to adopt IOU profiles, expressing concern for inaccuracy. However, inherent in all the options in this section of the final rule is our

belief that a COU's customers' profiles are probably as similar to customers' profiles in a nearby IOU as an IOU's customers' profiles are to each other, that the increased consistency resulting from the options will make participation in Maine's market easier for suppliers, and that requiring COUs to separately sample and calculate loads results in unnecessary costs. We encourage COUs to find means to combine their operations with neighboring IOUs whenever practicable.

D. Section 3: Telemetering

Section 3 addresses required and optional telemetering. During the Inquiry stage, commenters strongly supported the benefits of telemetering for as many customers as possible, citing accuracy as important to competitive electricity suppliers during the settlement process. However, all commenters recognized that the cost of telemetering was prohibitive for some customers and that marketers will discover the customers who are most cost-effective to telemeter. Other states have chosen differing levels of load to define customers who must receive mandatory telemetering. We proposed that only customers above 400 kW receive mandatory telemetering and that remaining customers be telemetered upon request. We were concerned that a deluge of requests for telemetering, with its accompanying data processing burden, would be impossible for utilities to accommodate, so we recommended a phase-in approach that would have allowed optional telemetering for only the larger customers during the first few years of retail access.

CMP and Dirigo supported the phase-in approach. MainePower objected to the phase-in of largest customers first, stating that it would be neither the most equitable nor the most efficient way to determine who should be telemetered. MainePower stated that smaller customers may find telemetering to be as beneficial as large customers, that requests might not outstrip utilities' abilities and that if they do, utilities should expand their capabilities. We believe that the competitive retail market will be healthier if customers and competitive electricity providers are able to install specialized meters based on the cost-effectiveness of such metering. We also do not wish to limit the benefits of retail competition to only large customers. We remain concerned that requests will outstrip utilities' ability to comply, but we suspect that it is unnecessarily cautious to prohibit telemetering through this rule. Therefore, in Section 3, we eliminate the phase-in provision from the proposed rule and allow optional telemetering for all customers. We include a three-criteria guideline for prioritizing requests whereby utilities must weigh the date the request was made, ease of implementation, and equity among customer groups. Finally, we leave in the rule the Commission's authority to implement a

phase-in based on the size of customer load, as a contingency against unexpected volume.

The proposed rule set 400 kW as the breakpoint above which customers must be telemetered. We noted that the majority of these customers are already telemetered, that costs quoted during the Inquiry to expand telemetering to all large customers did not appear excessive, and that the variability in these customers' loads makes profiling particularly ineffective. BHE and MPS commented that the 400 kW breakpoint added complexity to their recovery and research costs because it did not correspond to their rate class breakpoint, which is 500 kW. We had hoped to maintain a consistent set of breakpoints for class definitions throughout the state. However, we conclude that the lack of such consistency will not deter suppliers from participating in Maine's market, whereas the added cost of accommodating profile group breakpoints that differ from rate class breakpoints could be significant. Therefore, the rule allows the breakpoint that triggers mandatory telemetering to be determined by each utility's rate class breakpoints.

The proposed rule specified that competitive electricity providers compensate transmission and distribution utilities for the incremental cost of optional telemetering. This provision was intended to improve the likelihood of economic efficiency in customer conversions. BHE, CMP and MainePower commented that, because customers may wish to telemeter for their own purposes, customers should also be allowed to pay for telemetering costs. We agree; however, this rule addresses telemetering within the context of load profiling and settlement, not within the broader context of all possible alternative metering. Customers' ability to request telemetering for their own purposes will be addressed in another proceeding.

E. Section 4: Load Profiles

Section 4 describes methods for developing load profiles. Load profiles are used by all states to represent the loads of customers for whom telemetering is not cost-effective.

Section 4 balances our goal of consistent statewide methods with our goal to avoid unnecessary research costs. There are three issues that significantly influence the balance. First, utilities do not have identical rate class breakpoints, and therefore the sampling they perform for costing purposes must be based on groups that differ among utilities. If the rule defines consistent statewide customer groups for load profiling purposes, most utilities would carry out sampling of two sets of customer groups - those defined by their rate class definition and those defined for load profiling. Second, some utilities are already conducting research using accepted sampling methods.

Changing sampling methodology in order to be consistent statewide would require that utilities re-sample, thereby incurring significant cost in the short term. Finally, sampling standards that have worked well for many years must be revised to accommodate the needs of settlement in a regional market. For example, new sampling methods must recognize that every hour of the day is important to financial settlement and that re-sampling schedules must respond to a rapid sample attrition to telemeters.

The proposed rule included language that specified a small number of sampling and profiling methods. In its comments, Logica claimed that a single statewide method would be more efficient because it would minimize disputes and allow cost-effective implementation. BHE suggested that a working group develop single statewide methodologies. As we have made clear in earlier notices, we prefer consistent statewide methods. However, we conclude that the cost savings resulting from full statewide consistency are less certain than the cost savings resulting from allowing utilities to carry out methods that accommodate existing methods.

In addition, we are concerned that consistency in the early days of retail access will limit the ability to incorporate new methods as they emerge in the industry. Therefore, the final rule is more flexible in its description of sample definition and sampling methods. However, we strongly urge utilities to combine their expertise and develop identical sampling methods over the long run and to reflect over time industry developments in their sampling technique. We expect utilities to inform the Commission, and thereby other interested parties, of emerging sampling methods and their benefits in the reporting phases required by the rule.

1. Section 4.A: Load Profiles for Customer Groups

Section 4.A.1 specifies that a load profile must represent an average customer in the group being profiled in order to allow easy comparison across the State. The section explains that a load profile represents some type of 24-hour day, but allows transmission and distribution utilities to determine the most useful day type indicators.

Section 4.A.2 defines three customer groups for which a load profile must be developed. The groups are generally the same as those in the proposed rule (residential, small commercial/industrial, and large commercial/industrial). Using three groups rather than utility rate classes creates a simple, consistent set of data for suppliers and is sufficiently accurate during initial stages of retail access.

MainePower and CMP commented that further stratification might be necessary over time, to create groups with less diversity. This possibility was discussed during the Inquiry stage, and no consistent stratification method emerged. We prefer to maintain simplicity and understandability in preference to additional accuracy that is not yet clearly useful. Utilities may further stratify as long as reporting at the group level is possible.

As discussed above, the complication of existing rate class breakpoints would necessitate two samples if we required each utility to carry out research for profile groups with different breakpoints than their rate classes. MPS, BHE and CMP commented that inconsistency between profile and rate class breakpoints would be costly. While we had hoped that stratifying samples would accommodate those differences, we accept the utilities' conclusion that the process would not be easy. The final rule allows utilities to choose the breakpoints between profile groups within predefined boundaries. Suppliers will receive profiles for somewhat differing groups of customers, but we believe that this fact will not deter supplier operation in Maine.

Section 4.A.3 allows transmission and distribution utilities to create deemed profiles for groups of customers whose load patterns are predictable by the nature of the technologies within the group. Examples of such groups are streetlights and traffic lights.

2. Section 4.B: Profiling Methodology

Section 4.B defines allowable statistical techniques for choosing the samples that will be metered from each customer profile group.

Section 4.B.1 addresses sampling accuracy. This provision was thoroughly examined throughout all comment phases. Our goals continue to be to create adequate accuracy for both load settlement and cost studies, to provide enough specificity for suppliers to understand and accept the process, and to maintain a level of statewide consistency. Although utilities have sampled accurately for years, the variable of interest has been some variation of winter peaking load, because that load has been a significant driver of vertically integrated utilities' costs.

For the purposes of load profiling, three complexities have arisen. First, accuracy will be important in every hour of the year because settlement occurs hourly. Second, inasmuch as peak load is important within the regional capacity market, it is each month's peak load that is of interest. Third, New England

peaks in summer not winter, so regional price variability is likely to be most affected by load in summer.

The proposed rule contained language that suggested two variables of interest - load at the time of winter peak and load at the time of summer peak. CMP, BHE and MPS all commented that a two-peak method is unlikely to improve the accuracy of the samples for settlement purposes. We agree that accuracy in any one hour does not necessarily improve accuracy in all other hours. CMP was the only commenter that suggested some alternative energy-related variables to address the need for accuracy in all hours. Although CMP's suggestion seems to present a reasonable approach, we are hesitant to replace one uncertain suggestion with another suggestion that may be equally uncertain.

Despite the difficulty of defining the best sampling method, we continue to believe that guidelines will benefit all participants. Therefore, the final rule imposes the industry standard 90/10 accuracy on load in the utility's month of summer peak for utilities operating in ISO-NE territory and 90/10 accuracy on load in the utility's month of winter peak for utilities operating outside ISO-NE territory. This method focuses on accuracy in a month when price variability has some likelihood of being greatest. While this month might not be the region's system peak, it is a reasonable proxy.

The rule also lists the variables whose accuracy is also important for regional settlement, namely, monthly peaks and all hours of the year, and requires that the sampling method chosen should take accuracy of these measurements into consideration. We recognize that no method can focus on all these measurements, so we have chosen to provide a reasonable first priority for the sake of expediency. This level of flexibility will allow utilities to experiment with methods that accomplish multiple goals as they emerge.

Section 4.B.2 specifies that samples must be revised every two years unless the utility shows that an existing sample is likely to still mirror the class it represents. We include a re-sampling requirement because attrition to telemetering may be rapid during the early stages of retail access.

We attempted to introduce specificity to rules governing re-sampling in the proposed rule. There are a number of reasonable re-sampling triggers - reduction below 90/10 accuracy is one, and an increasing difference between estimated and metered energy is another. However, in response to comments, we conclude that specifying a single re-sampling trigger might result in costly re-sampling that does not improve accuracy.

CMP expressed concern that the rule's language would require that new samples unnecessarily replace samples that currently exist. The language in the final rule avoids that problem. However, the rule does require that utilities examine their existing samples chosen more than two years ago in response to the re-sampling provision. In addition, we note that existing utility samples usually represent rate classes, not profile groups. Therefore, utilities that intend to continue to use existing samples must convert sample result into profile group data.

Finally, parties have expressed uncertainty as to whether sampling must be ongoing for all profile groups. The rule does require concurrent, ongoing sampling of each profile group. Transmission and distribution utilities that are not currently sampling their entire customer base must initiate sampling as soon as possible.

Section 4.B.3 specifies that samples be chosen using the widely accepted statistical methods of either simple random sampling or stratified random sampling. Section 4.B.4 specifies that sample meter readings be converted to estimated class values through the widely accepted statistical methods of either ratio analysis or mean-per-unit analysis. No commenter objected to these provisions of the proposed rule.

F. Section 5: Daily Estimation of Competitive Electricity Provider Hourly Loads

Section 5 describes the process that each transmission and distribution utility must conduct at the end of each day to estimate each competitive electricity provider's hourly load obligations. These estimations will be given to ISO-NE, which will use them to track the balance of generation and load in the bulk power system.

Section 5.A specifies that hourly loads at the point of delivery must first be estimated for each customer. This step is a preamble to adding customers' loads into an aggregate provider load. Telemetered customers' loads will equal the meter readings. Profiled customers' loads will begin as the class load profile for that day, which represents an average customer. The profile chosen must represent conditions (e.g., time of year, time of week, and weather conditions) that are known to significantly influence load patterns. The profile may either be chosen from a proxy day that is similar to the day being estimated, or a generic profile may be adjusted upward or downward through regression or some other form of analysis to reflect the influencing conditions.

Each hourly load must then be adjusted upward or downward so that total daily kWh usage from the hourly loads will equal a "kWh usage factor" that is the best estimate of that customer's kWh usage for that day. The rule is silent on the best way to calculate each customer's kWh usage factor because we believe there are a variety of valid estimation methods. However, we envision that a customer's kWh usage factor is likely to be derived from its monthly metered kWh use adjusted to turn cycle-month kWh use into calendar-month kWh use.

Section 5.B.1 specifies that all customer loads will be adjusted for line losses between the bulk power system meter and the point of delivery, to produce load used by each customer at the point of delivery to the transmission and distribution utility's territory. The loads served by each competitive electricity provider will then be aggregated by adding the hourly loads of each customer served by that provider.

In a perfectly modeled system, the sum of the loads served by all competitive electricity providers would equal the meter readings of the bulk power system meter in each hour. However, inaccuracies introduced by sampling and line loss variabilities will produce a difference between the bulk power system meter readings and the estimated system loads. The rule requires that these differences in each hour be allocated to profiled customers. MainePower and Logica commented that differences could reasonably be allocated to telemetered customers, if we believe that the bulk of the difference is attributable to line losses, but left the best method to our discretion. We appreciate these comments. We believe that the bulk of the difference is attributable to sampling variability and therefore leave unchanged the language of the proposed rule.

Section 5.B.2 states the purpose for calculating the hourly load estimations. It clarifies that these calculations are to conform to reporting requirements of the bulk power system administrator.

Section 5.B.3 assigns responsibility for retail line losses to competitive electricity suppliers and requires that line loss estimates be differentiated by season and by voltage level at a minimum. We have incorporated the refinement suggested by MainePower, which clarifies that competitive electricity providers are responsible only for losses attributable to retail delivery inside the transmission and distribution utility's bulk meter. Logica commented that line losses outside the bulk meter must be reported to ISO-NE. We do not understand this to be true; if ISO-NE subsequently requires such reporting, we will accommodate its requirement.

G. Section 6: Monthly Settlement of Competitive Electricity Provider Energy Use

Section 6 describes the process that each transmission and distribution utility will carry out at the end of each month to re-estimate the load obligation in each hour of the competitive electricity suppliers operating in its territory. These estimates will be given to ISO-NE, which will use them to carry out the financial settlement that takes place after balancing load obligation and generation delivered by each competitive electricity provider.

In this section, we considered likely developments in the ISO monthly settlement procedures. Currently, ISO-NE requires receipt of only a single monthly kWh energy difference between estimated loads and month-end calculated loads for each competitive electricity provider. That difference is used to adjust the financial settlement determined by the hourly load obligations received throughout the month by a single monthly average price. We believe that this requirement will evolve, and that ISO-NE will require hourly differences at some future date. The rule requires transmission and distribution utilities to implement a process that will accommodate that evolution, thereby avoiding costly upgrades at a later date.

Section 6.A specifies that hourly loads be recalculated, incorporating updated estimates of each customer's daily energy use derived from monthly meter reading for billing purposes. The rule is silent as to the best way to incorporate the updated usage estimates because we believe there are a variety of valid estimation methods. We expect that the method will recognize the fact that the updated meter readings are at the point of delivery and must be adjusted for line losses. We require recalculation of each hour in anticipation of future ISO requirements, as discussed in the previous paragraph.

Section 6.B specifies that the transmission and distribution utility will calculate the differences between the daily estimates and the monthly updated estimates. We revised the language in the proposed rule to refer to "monthly" meter readings in response to CMP's comment that meter readings are done on a cycle basis. MPS commented that it currently reads meters every other month and that monthly reading will create additional costs; however, MPS did not object to making that process change because the competitive market will require it.

Section 6.B.2 states the purpose for calculating the monthly energy difference estimations. It clarifies that these calculations are to conform to reporting requirements of the bulk power system administrator.

No commenters disagreed with the substantive provisions of this Section in the proposed rule. Therefore, we made no significant changes.

H. Section 7: Information Access

Section 7 specifies what entities have access to customer-specific and provider-specific load data. The provisions are confined to data that are relevant for load estimation and settlement. A competitive electricity provider should have easy, fast, and complete access to any data that is used for its own financial settlement and have provided this in the rule. In addition, a competitive electricity provider should have access to any load data of its own customers. However, the legislation currently imposes a condition that "distribution utilities may not release any proprietary customer information without the prior written authorization of the customer." 35-A M.R.S.A. § 3205(3)(I) This constraint appears in some instances to be unusually restrictive. For example, it seems reasonable that a competitive electricity provider should be allowed to receive data describing its own customers without explicit written authorization. It may also be reasonable that historic data (i.e., customer-specific data from a period *before* the customer received service from the specific competitive electricity provider) should be available without written authorization. We will consider asking the legislature to modify this requirement. In the meantime, the rule allows the competitive electricity provider to receive customer-specific load data as easily as the law ultimately allows.

Comments on Section 7 did not disagree with the data to be provided. However, all commenters suggested that written customer authorization was burdensome and that, when authorization is required, third-party authorization should be acceptable. Commenters generally recognize the problems caused by the language of the legislation.

We removed provisions for access to billing data, which will be addressed in another proceeding.

Section 7.A specifies that competitive electricity providers will receive daily load estimations automatically, without requesting it. This is aggregate data and is clearly allowed. We require automatic release rather than on-request release to avoid an extra layer of communication that we consider unnecessary. We have modified the language to require that data be sent to competitive electricity providers as soon as practicable. Our intent is that transmission and distribution utilities provide competitive electricity providers with the data as soon as it is provided to ISO-NE and that the data be identical to that given to ISO-NE.

We also modified the language to clarify that the time frames contained in this provision are to conform to requirements of the bulk power system administrator.

The rule allows competitive electricity providers to make unlimited requests for 12 months of historical data. There is no need for a provider to request 12 months of data more than one time, at the time of customer enrollment. After that, the provider will receive all load data. The cost of repeated requests could be significant. This issue was not addressed in comments on the proposed rule, so we have left the language intact. However, if repeated unnecessary requests become burdensome to transmission and distribution utilities, we will consider limiting the frequency of provider requests.

Section 7.B is an identical provision that applies to monthly energy settlement estimates.

Section 7.C specifies that customer group load profiles be made public. We expect that the hourly load estimates that comprise the profiles will be published on each utility's web site, with some indication of each profile's day type or other relevant information.

I. Section 8: Data Transfer

Section 8 requires that transfer of data calculated pursuant to these rules follow guidelines determined by the Electronic Business Transactions (EBT) Standards group, a statewide group that is charged with developing guidelines for electronic data transfer among transmission and distribution utilities, competitive electricity providers, and bulk power system administrators. The protocol and form of electronic transfer will be determined by ISO-NE; the EBT group will determine how to accomplish ISO-NE's transfer requirements within Maine.

J. Section 9: Reporting

Section 9.A requires that transmission and distribution utilities submit to the Commission a description of their sampling, profiling, validation, and daily and monthly settlement methods before the advent of retail access. The purpose of this report is to allow the Commission to maintain an understanding of the processes being followed in all areas affecting the implementation of retail access. It also allows competitive electricity providers to understand each transmission and distribution utility's process with sufficient accuracy to predict its own daily load obligations. BHE commented that the dates specified in the proposed rule are too late to be useful

and proposed instead a working group to develop methods. We have changed the reporting dates. We will not require a working group, but as discussed earlier, we would view favorably a cooperative effort among statewide parties to develop consistent methods.

MainePower commented that each utility's methods should be published on its web page. We have not included this provision in the rule. However, we agree with the comment because we believe that all information required by competitive electricity providers to do business in Maine's retail market should be available on an easily-discovered web page. We will work with the EBT group to see that such a web page contains profiling methods, profiles, and line losses.

Section 9.B requires that transmission and distribution utilities submit to the Commission an annual report whose purpose is to keep the Commission apprised of the effectiveness of the processes it has implemented through this Rule. The annual report should revise the original methodology report if necessary and should present suggestions for methodology changes in response to emerging industry knowledge.

Section 9.C requires transmission and distribution utilities to submit line loss studies by March 1, 1999 and March 1, 2001.

Accordingly, we

O R D E R

1. That the attached Chapter 321, Load Obligation and Settlement Calculations for Competitive Providers of Electricity, is hereby adopted;
2. That the Administrative Director shall file the adopted rule and related material with the Secretary of State; and
3. That the Administrative Director shall send copies of this Order and attached Rule to:
 - A. All electric utilities in the State;
 - B. All persons who have filed with the Commission within the past year a written request for Notice of Rulemaking;
 - C. All persons on the Commission's electric restructuring service list, Docket No. 95-462;

D. All parties listed on the service list in Docket No. 98-496 and Docket No. 97-861; and

E. Executive Director of the Legislative Council (20 copies).

Dated at Augusta, Maine, this 13th day of October, 1998.

BY ORDER OF THE COMMISSION

Dennis L. Keschl
Administrative Director

COMMISSIONERS VOTING FOR: Welch
 Nugent
 Diamond